Kemper County Storage Complex

Proposed Injection Well 19-2

Mississippi Power Company

Pre-Operational Testing Plan

40 CFR 146.82(a)(8), 146.87

Facility Information

Facility Name:	Kemper County Storage Complex Well Name: MPC 19-2
Facility Contact:	Mississippi Power Company Environmental Affairs P.O. Box 4079 Gulfport, MS 39502-4079
Well Location:	Kemper County, Mississippi Latitude: 32.6130560 Longitude: -88.8061110

Pre-Operational Logging and Testing GSDT Submissions
GSDT Module: Pre-Operational Testing ***Tab(s):*** Welcome tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☐ Proposed pre-operational testing program ***[40 CFR 146.82(a)(8) and 146.87]***

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List of Acronyms/Abbreviations

AoR	Area of Review
CCUS	Carbon capture, utilization, and storage
CO_2	Carbon dioxide
CMG	Computer Modelling Group
DOE	Department of Energy
ECO_2S	Establishing An Early Carbon Dioxide Storage
EPA	Environmental Protection Agency
ERRP	Emergency and Remedial Response
ft	feet
mg/L	milligrams per liter
MMt	Millions of Metric tons
MPC	Mississippi Power Company
PCC	Porters Creek Clay
PISC	Post-Injection Site Care
psi	Pounds per square inch
RCA	Routine Core Analysis
SS	Sub- Sea
TMS	Tuscaloosa Marine Shale
TVD	True Vertical Depth
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water

A. Overview of Pre-Operational Testing Program

The pre-operational testing program will be implemented to obtain an analysis of the chemical and physical characteristics of the injection and confining zones and to meet the testing requirements of 40 CFR 146.87 and well construction requirements of 40 CFR 146.86. The pre-operational testing program will include a combination of logging, coring, formation hydrogeologic testing (e.g., a pump test and/or injectivity tests), and other activities during the drilling and construction of the proposed CO_2 injection well.

The pre-operational testing program will determine or verify the depth, thickness, mineralogy, lithology, porosity, permeability, and geomechanical information of the confining zone (Tuscaloosa Marine Shale), injection interval (Paluxy Formation), and other geologically relevant formations identified within the injection zone. In addition, formation fluid characteristics will be obtained from the Paluxy Formation to establish baseline data against which future measurements may be compared after the start of injection operations. The results of the testing activities will be documented in a report and submitted to the EPA within 60 days after the well drilling and testing activities have been completed and prior to the start of CO_2 injection operations.

Mississippi Power Company (MPC) will rely on and utilize the geologic and petrophysical data that has been collected and analyzed during MPC's extensive site characterization effort at the Kemper County Storage Complex. MPC will elect to bypass taking core samples from the injection well. Based off of previous coring attempts within the AoR, this would potentially increase the risk of wellbore integrity issues as the processes associated with drilling and collecting core while drilling fluids are circulated for long periods of time can contribute to formation washout. Similarly, formation and fracture testing will also pose increased risks associated with washouts along the wellbore given the extended circulation period of drilling fluids that these activities require. Detailed geomechanical work is outlined in section 1.2.6 of the *Application Narrative* where core and log analysis were input into a 1-dimensional Mechanical Earth Model (1-D MEM) that gave prudent information related to the understanding of formation mechanical properties and fracture gradient of the proposed injection reservoir and surrounding geologic formation. Given the unique geologic setting and challenges that have been observed at the Kemper County Storage Complex, MPC concludes that it would be prudent to avoid activities, such as coring and fracture tests, to prevent washouts and other risks from occurring in the proposed injection well.

MPC will rely on geologic and petrophysical tests from existing characterization and monitoring wells to satisfy the Class VI rule requirements for the future injection wells at the Kemper County Storage Complex. MPC will use Tuscaloosa Marine Shale and Paluxy Formation core samples collected from the MPC 19-1 characterization well to satisfy the requirement of 40 CFR 146.87 (b) for the proposed MPC 19-2 injection well, which will be on the same pad as the MPC 19-1 (**Figure 1**). MPC will share similar core data that has been collected from other characterization wells in the area as a part of the characterization effort. A second proposed injection well (MPC 32-1) is planned approximately 2 miles to the southeast of the proposed MPC 19-2 and will be covered in more detail in a separate permit application. Additional details are provided in the subsequent sections of this chapter to describe the rationale for opting to forego additional coring and fracture testing activities for the proposed injection well.

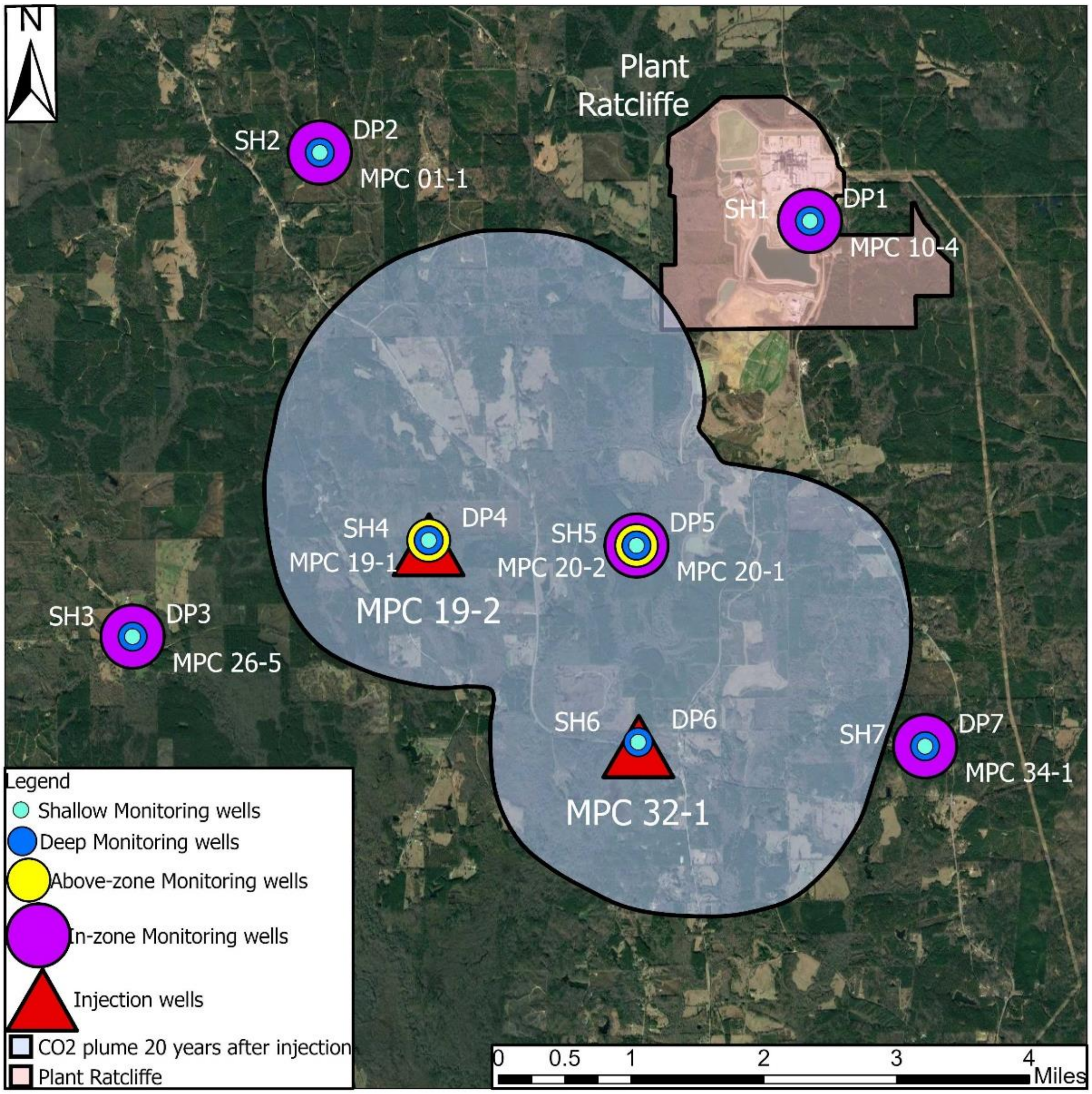

Figure 1: Locations of proposed injection and monitoring wells, drilled characterization wells, and Plant Ratcliffe at the Kemper County Storage Complex

B. Wireline Logging

Open-borehole logs will be run to obtain densely spaced, in-situ, structural, stratigraphic, physical, chemical, and geomechanical information for the confining zone and injection zone. Logs, surveys, and tests will ensure conformance with the injection well construction requirements according to CFR 146.86 and establish accurate baseline data for future comparison. Open-borehole characterization logs will be obtained at the surface casing point as well as the long-string casing point (i.e., total borehole depth) in the vertical pilot borehole. Open-borehole wireline logs will not be run in the 30-in.-diameter conductor casing borehole because logging tools are not suited for this large-diameter hole size. See **Table 1** for a list of the various Surface and Long string Casing wireline logging tools that were deployed for MPC 19-1.

Table 1: Wireline Logging Program for MPC 19-1

Depth Interval (ft)	Log	Purpose/Comments
Surface Casing		
0 – 1,500	Mudlog	Monitor and ensure uninterrupted drilling process as well as provide lithologic information while drilling
0 – 1,500	Compensated Neutron, Lithodensity, Array Induction, GR, SP, Caliper	Characterize basic geology (lithology, mineralogy, porosity) Evaluate borehole condition prior to cementing
0 – 1,500	Cement bond log	Evaluate cement integrity
Long String Casing		
1,500 – 5,750	Mudlog	Monitor and ensure an uninterrupted drilling process as well as provide lithologic information while drilling
1,500 – 5,750	Temperature Log	Determine natural geothermal gradient outside well for comparison to future temperature logs for external mechanical integrity evaluations. Baseline log is run a minimum of 30 days after drilling and casing/cementing the well because temperature anomalies due to circulation of drilling fluid and/or open-borehole injection testing will persist for several weeks to months.
1,500 – 5,750	Borehole Profile	Evaluate borehole condition prior to cementing
1,500 – 5,750	Combinable Magnetic Resonance Tool	Enhanced characterization of geologic and geomechanical properties that control injectivity and caprock/seal integrity.
1,500 – 5,750	Compensated Neutron, Lithodensity, Array Induction, GR, SP, Caliper	Characterize basic geology (lithology, mineralogy, porosity) Evaluate borehole condition prior to cementing
1,500 – 5,750	Cement bond log	Evaluate cement integrity
1,500 – 5,750	Formation Micro Imager	Enhanced characterization of geologic and geomechanical properties that control injectivity and caprock/seal integrity.
1,500 – 5,750	Dipole Sonic	Determine the reservoir fracture pressure gradient and geomechanical properties of the injected zones

C. Coring

MPC has collected sections of whole core from the confining zone and injection zone while drilling the characterization and observation wells, of which three (MPC 10-4, MPC 34-1, and MPC 19-1; seen in **Figure 1**) were utilized as part of the core analysis program. Core was taken from formations in the confining and injection zones: Tuscaloosa Marine Shale, Lower Tuscaloosa Massive Sand, Washita-Fredericksburg Interval (Upper and Basal shales), and Paluxy Formation. Since the proposed injection well will be on the same pad as the MPC 19-1, where whole core was collected in 2021, no additional core will be collected. Analysis of the cores that have been previously cut in conjunction with the log analysis conducted as part of the geologic site characterization has demonstrated consistency of the key aspects (presence, thickness, porosity, permeability) of geology and reservoir quality across the AoR. Additionally, as a means of best practice and maintaining appropriate wellbore stability and solid cement bonding, it is best that no extra procedures be introduced to the drilled injection wells to avoid complications and risks associated with formation washout. The full suite of coring tests conducted and summary of the core analysis results can be found in section 1.2.5 of the *Application Narrative*.

D. Fluid Sampling

MPC collected in-zone fluid samples from the Paluxy Formation, from the MPC 10-4 well located 4 miles from the proposed 19-2 injection well (**Figure 1**), and these samples will serve to establish the baseline of reservoir conditions for fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone. MPC will collect additional fluid samples from MPC 19-2 as a means of comparison to baseline fluid and geochemical properties that have been established for the Paluxy Formation from the MPC 10-4 well. The fluid sample analysis from the MPC 10-4 and proposed MPC 19-2 wells will be used to satisfy the requirement of 40 CFR 146.87 (5)(c) and ensure that the baseline geochemical properties are established for the Paluxy Formation across the AoR for the Kemper County Storage Complex.

The fluid sampling parameters to be analyzed as part of fluid sampling in the injection zone and associated analytical methods are presented in **Table 2**, which are consistent with the fluid sampling analysis and processes that are detailed in the *Testing and Monitoring Plan* and the *Quality Assurance Surveillance Plan* associated with this permit. MPC will also collect hydrogeologic data from the extensive wireline program that was discussed previously in this plan.

Table 2: Summary of Analytical and Field Parameters for Fluid Sampling in the Paluxy Formation

Parameters	Analytical Methods
Paluxy Formation (Injection Interval)	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, and Tl	ICP-MS, EPA Method 6020
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010B
Anions: Br, Cl, F, NO_3 and SO_4 Dissolved CO_2	Ion Chromatography, EPA Method 300.0 Coulometric titration, ASTM D513-11
Total Dissolved Solids Water Density Alkalinity pH (field) Specific conductance (field) Temperature (field)	Gravimetry, APHA 2540C Oscillating body method APHA 2320B EPA 150.1 APHA 2510 Thermocouple

Once the long casing string has been set and cement has been given sufficient time to harden, perforations will be made through the target injection interval and fluid samples will be collected via wireline tool. An example of such a tool is the Kuster Flow Through Sampler (FTS). The FTS, which looks like a narrow cylinder, is a device for obtaining fluid samples from a producing well. The sample chamber is lowered into the well via wireline with open valves on each end, allowing well fluids to pass freely through the chamber. At an interval programmed on the surface, the valves close, trapping the fluid. The sampler can then be removed from the well. It is important to note that any fluids introduced into the formation during drilling, borehole conditioning, acid treatment, and/or formation (injection) testing will first need to be removed before representative fluid samples can be collected. Consequently, it is desirable to collect fluid samples during the active drilling phase rather than after well completion. Fluid samples can be collected after well completion by swabbing fluid or pumping through tubing with a packer set just above the perforated interval to minimize the amount of fluid that must be removed from the well. The combination of the fluid sampling and wireline logging program discussed in this plan will satisfy the requirements of 40 CFR 146.87(d).

E. Mechanical Integrity Testing

MPC will conduct tests and logs as needed to demonstrate the internal and external mechanical integrity of the injection wells prior to initiating regular CO_2 injection, satisfying the hydrogeologic testing requirements under 40 CFR 146.87(e). Internal mechanical integrity refers to the absence of leaks in the tubing, packer, and casing above the packer. External mechanical integrity refers to the absence of fluid movement/leaks through channels adjacent to the injection wellbore that could result in fluid migration into an USDW.

As required by the Mississippi State Oil and Gas Board, prior to drilling out the plug on each casing string, a casing pressure test will be conducted. The test will be designed not to exceed the rated pressure of the casing. Surface casing should be tested at 1,000 psi and with water present in the top 100ft of the casing string. Long string casing will be tested at 1,500 psi or .2 psi/ft, whichever is greater [1]. If a decline in pressure greater than 10% within the first 30 minutes of testing is noted, or if other indications of a leak are present, then the casing string will need to be recemented, repaired, or have an additional casing string ran. Once remedial measures have taken place, the pressure test will be

[1] Mississippi State Oil & Gas Board. *Title 26, Part 3: Rules and Regulations Governing Oil and Gas Drilling, Producing and Pipeline Operations in Submerged Offshore Land of the State of Mississippi.*

conducted again. After cementing the casing strings, drilling will not commence until either 24 hours has passed or a time lapse of 8 hours for the conductor casing and 12 hours for other casing strings. All casing pressure tests will be recorded in the driller's log[1].

After the proposed injection well MPC 19-2 is completed, including the installation of tubing, packer, and annular fluid, a test of the well's internal mechanical integrity will be performed by conducting an annular pressure test within 24 hours of the cement setting. The annular pressure test is a short-term test wherein the fluid in the annular space between the tubing and casing is pressurized, the well is shut-in (temporarily sealed up), and the pressure of the annular fluid is monitored for leak-off. The planned procedure will be to provide a comparison of the pressure change throughout the test period to 3% of the test pressure (0.03 × test pressure). If the annulus test pressure decreases by this amount or more, the well has failed to demonstrate internal mechanical integrity. If the annulus pressure changes by less than 3% during the test period, the well has demonstrated internal mechanical integrity. If the well fails the annular pressure test, the tubing and packer will need to be removed from the well to determine the cause of the leak. During the active CO_2 injection phase, internal mechanical integrity will be continuously monitored by the well annular pressure maintenance and monitoring system, as discussed in more detail in the *Testing and Monitoring Plan*.

MPC will also employ various methods to demonstrate external mechanical integrity upon the completion of the proposed CO_2 injection well MPC 19-2 and prior to the start of injection operations. MPC will run PNC and temperature logs on the completed injection well in order to demonstrate external mechanical integrity, with these logs also providing supporting hydrogeologic data that are discussed later in this section. MPC will run an ultrasonic cement bond log to provide an additional confidence that there are no pathways for potential CO_2 migration through the wellbore, casing, or cement prior to injection operations, satisfying the requirement of 40 CFR 146.87 (a)(3).

F. Fracture Pressure of Injection and Confining Zones

MPC intends to satisfy the requirements of 40 CFR 146.87 (d) by running a dipole sonic log, which will enable MPC to calculate the reservoir fracture pressure of the confining zone and injection interval. MPC will not plan on completing an open-hole fracture pressure test due to the increased risk of washouts in the unconsolidated geologic formations of interest, which could potentially result in the creation of a pathway for CO_2 leakage. Previous attempts on project characterization wells haven't been able to achieve a high enough rate through tubing to part the formation. As detailed previously in this plan, the results of the 1-D MEM have provided an understanding of the formation mechanical properties and fracture gradient of the injection and confining zones. In an effort to maintain wellbore stability the goal will be to drill the proposed injection well with limited additional testing to limit borehole rugosity and provide the highest probability of achieving a mechanically sound cement job.

G. Hydrogeologic Testing

MPC intends to run a Composite Injectivity Evaluation test on the Paluxy Formation to determine the large-scale composite injectivity (transmissivity) of the injection interval and possible presence of nearby hydrogeologic boundaries (**Table 3**). Additionally, this evaluation will collect fluid samples from select permeable zones in the injection interval for geochemical analysis. MPC intends to use the extensive wireline logging program to support and corroborate the hydrogeologic properties that are collected via direct fluid sampling from the injection zone. Additionally, MPC will collect geochemical data such as reservoir pressure from the Paluxy Formation.

Table 3: Composite Injectivity Evaluation Testing Program

Test	Description	
Paluxy Formation Composite Injectivity Evaluation	Objectives	**Primary objective:** To determine the large-scale transmissivity of the Paluxy Formation and possible presence of nearby hydrogeologic boundaries and will provide direct information about the injectivity potential of the Paluxy Formation or a selected portion of it. **Secondary objective:** Prior to the injection test a representative formation sample would be collected. To collect representative formation fluid samples either by swabbing or pumping over select permeable horizons to conduct detailed hydrochemical analysis.
	Test/Depth Zone	The Paluxy Formation. Approximate depth interval 4,700 to 5,100 ft measured depth. Alternatively, this test may be conducted on one or more discrete depth intervals within the Paluxy Formation.
	Test Activity/ Summary	A single packer would be placed at the top of the Paluxy Formation or inside the casing string near the bottom. After the packer is in place, a constant-rate injection utilizing produced or inhibited fluid will be conducted. At the end of injection the recovery pressure for the composite zone monitored for a period ≥1.5 times the injection period. If this test is conducted on a discrete depth interval within the Paluxy, a straddle-packer or tandem single-packers may be used for test zone isolation.

A fall-off test measures and analyzes pressure data taken after an injection is halted and the well is “shut-in” (temporarily sealed up). A pre-operation pressure fall-off test serves as the baseline test for establishing reservoir and well conditions for comparison to results of subsequent pressure fall-off tests conducted during the operational period (i.e., during CO_2 injection). Specifically, this comparison is intended to confirm that the pressure increase within the injection interval is less than that predicted and ensure that the modeled parameters used in the *Area of Review and Corrective Action Plan* modeling analysis represent actual conditions [2].

The guidelines of EPA Region 6 [3] defines a pressure fall-off test as a pressure transient test that consists of shutting in an injection well after a period of prolonged injection and measuring the pressure fall-off and this practice will be followed for the purposes of this project. The fall-off period is a replay of the injection preceding it;

[2] EPA (U.S. Environmental Protection Agency). 1990. Ambient Pressure Monitoring. EPA Region 5, Regional Guidance #6. Washington, D.C.

[3] EPA (U.S. Environmental Protection Agency). 2002. EPA Region 6 UIC Pressure Falloff Testing Guideline. Washington, D.C.

consequently, it is affected by the magnitude, length, and rate fluctuations of the injection period. Fall-off testing analysis provides reservoir and well parameters, including transmissivity, storage capability, skin factor, and well flowing and static pressures. Establishing a baseline value for these parameters will be useful for identifying changes in the well and/or reservoir properties after CO_2 injection begins; for example, an increasing skin factor may be indicative of formation damage which signals a need for well remediation while a decreasing skin factor may indicate near-wellbore cleanup.

The baseline pressure fall-off test will be conducted as part of the post-completion injectivity testing (e.g., constant-rate injection test conducted as either a single-well test and/or multi-well interference test) discussed in the following section. Guidance for conducting the pressure fall-off test in this project is provided by EPA Region 5 [4] [5]. In general, the recommendations provided in these guidance documents will be followed to the extent practicable. If circumstances dictate steps are required outside of the guidance provided, the proposed operations plan will be cleared with the UIC Program Director prior to initiation.

H. Stimulation Program

The need for stimulation to enhance the injectivity potential of the Paluxy Formation is not anticipated. Modeling based on data collected from the geologic site characterization has concluded that the storage reservoir is of high quality due to the relatively high porosity (28%) and permeability (average 1,600mD). More information regarding the reservoir properties can be found throughout the *Application Narrative*. In the unlikely event stimulation techniques are needed to bypass any drilling induced damage, a well stimulation plan will be developed and submitted to EPA Region 4 for review and approval prior to commencing these operations.

[4] EPA (U.S. Environmental Protection Agency). 1990. *Ambient Pressure Monitoring*. EPA Region 5, Regional Guidance #6. Washington, D.C.

[5] EPA (U.S. Environmental Protection Agency). 1998. Planning, Executing, and Reporting Pressure Transient Tests. EPA Region 5 – Underground Injection Control Section Regional Guidance #6. Washington D.C.

I. Schedule

The owner or operator will provide the UIC Program Director with the opportunity to witness all logging and testing by this subpart. Pursuant to 40 CFR 146.87 (f) the owner or operator will submit a schedule of such activities to the UIC Program Director 30 days prior to conducting the first test and submit any changes to the schedule 30 days prior to the next scheduled test. The scheduled testing will be developed within 90 days following the permission for the construction of the proposed injection well.